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U.S. Nuclear Regulatory Commission
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Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

Supplement to License Amendment Request to Exclude the Dynamic Effects Associated with Certain Postulated Pipe Ruptures From the Licensing Basis Based Upon Application of Leak-Before-Break Methodology – Response to Request for Additional Information (TAC Nos. ME2976 and ME2977)

References:

1. Letter from Northern States Power Company, a Minnesota corporation, to the Nuclear Regulatory Commission, "License Amendment Request to Exclude the Dynamic Effects Associated with Certain Postulated Pipe Ruptures From the Licensing Basis Based Upon Application of Leak-Before-Break Methodology," L-PI-09-134, dated December 22, 2009, ADAMS Accession Number ML100200129.

2. Letter from T. Wengert (NRC) to M. Schimmel (NSPM), "Prairie Island Nuclear Generating Plant, Units 1 and 2 – Request for Additional Information Related to License Amendment Request to Exclude the Dynamic Effects Associated with Certain Postulated Pipe Ruptures From the Licensing Basis Based Upon Application of Leak-Before-Break Methodology (TAC Nos. ME2976 and ME2977)," dated June 10, 2010, ADAMS Accession Number ML101550668.

In Reference 1, Northern States Power Company, a Minnesota corporation (NSPM), doing business as Xcel Energy, submitted a License Amendment Request (LAR) for the Prairie Island Nuclear Generating Plant (PINGP), Units 1 and 2, to apply leak-before-break methodology to piping systems attached to the reactor coolant system (RCS). In Reference 2, the Nuclear Regulatory Commission (NRC) Staff requested additional information to support review of Reference 1.

1717 Wakonade Drive East • Welch, Minnesota 55089-9642
Telephone: 651.388.1121

Enclosure 1 to this letter provides the responses to the NRC Staff requests for additional information, with the exception of questions regarding RCS leakage detection. Due to circumstances unrelated to the subject LAR, NSPM is re-evaluating the PINGP RCS leak detection system capabilities and will provide responses to these questions upon completion of that evaluation. NSPM submits this supplement in accordance with the provisions of 10 CFR 50.90.

The supplemental information provided in this letter does not impact the conclusions of the Determination of No Significant Hazards Consideration and Environmental Assessment presented in the Reference 1 submittal.

In accordance with 10 CFR 50.91, NSPM is notifying the State of Minnesota of this LAR supplement by transmitting a copy of this letter to the designated State Official.

If there are any questions or if additional information is needed, please contact Sam Chesnutt at 651-267-7546.

Summary of Commitments

This letter contains no new commitments and no revisions to existing commitments.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on JUL 23 2010

Mark A. Schimmel
Site Vice President, Prairie Island Nuclear Generating Plant
Northern States Power Company - Minnesota

Enclosure (1)

cc: Administrator, Region III, USNRC
Project Manager, PINGP, USNRC
Resident Inspector, PINGP, USNRC
State of Minnesota

ENCLOSURE 1

Response to NRC Request for Additional Information Dated June 10, 2010, Related to License Amendment Request to Exclude the Dynamic Effects Associated with Certain Postulated Pipe Ruptures From the Licensing Basis Based Upon Application of Leak-Before-Break Methodology at the Prairie Island Nuclear Generating Plant

This enclosure includes responses from the Northern States Power Company, a Minnesota corporation (NSPM), to Requests for Additional Information (RAI) provided by the Nuclear Regulatory Commission (NRC) in a letter dated June 10, 2010 (ADAMS accession number ML101550668). These RAI responses are provided in support of NSPM's License Amendment Request (LAR) for the Prairie Island Nuclear Generating Plant (PINGP), submitted December 22, 2009 (Reference 1, ML100200129), and address information in the following enclosures to that LAR:

LAR Enclosure 1: Evaluation of the Proposed Change.

LAR Enclosure 2: Updated Leak-Before-Break Evaluation for Several Reactor Coolant System (RCS) Piping, Structural Integrity Associates Report 0900634.401, evaluates piping that attaches to the RCS.

LAR Enclosure 3: Updated LBB Report for Unit 2 Pressurizer Surge Line, Structural Integrity Associates Report 0900634.402, evaluates the weld overlay on the pressurizer surge line nozzle-to-safe-end weld.

LAR Enclosure 4: Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis, Unit 2, Westinghouse evaluation WCAP-15379, evaluates the pressurizer surge line with the exception of the weld overlay evaluated in Enclosure 3.

This Enclosure quotes each RAI question in italics and each question is followed by the NSPM response. Referenced documents are listed at the end of this Enclosure.

Enclosure 1 to the December 22, 2009 Submittal

E1-1. Pages 1 and 2: *Item 4 states that the safety injection line consists of a 4-inch diameter pipe and a 6-inch diameter pipe. Item 5 states that the RCS draindown line consists of a 2-inch pipe reducer and a 6-inch diameter pipe.*

E1-1, Subpart (1):

Discuss the approximate length of the 4-inch diameter and 6-inch diameter pipe segments in the safety injection line. Discuss the approximate length of the 2-inch diameter and 6-inch diameter pipe segments in the RCS draindown line.

NSPM Response:

For Unit 1 Loop A, the 4-inch diameter pipe segment of the safety injection (SI) line is approximately 106 inches in length and the 6-inch diameter segment is approximately 62 inches in length.

For Unit 1 Loop B, the 4-inch diameter pipe segment of the SI line is approximately 228 inches in length and the 6-inch diameter segment is 0 inches in length.

For Unit 2 Loop A, the 4-inch diameter pipe segment of the SI line is approximately 120 inches in length and the 6-inch diameter pipe segment is approximately 11 inches in length.

For Unit 2 Loop B, the 4-inch diameter pipe segment of the SI line is approximately 221 inches in length and the 6-inch diameter pipe segment is approximately 12 inches in length.

It is noted that the 2-inch diameter segment in the draindown line is actually 3 inches in diameter. This inadvertent error in the Reference 1 submittal does not affect the LBB evaluation because the 3-inch line was not analyzed. For Unit 1, the 3-inch diameter portion of RCS draindown line is 29.5 inches in length and the 6-inch portion of draindown line is 4 inches in length

For Unit 2, the 3-inch diameter pipe segment of RCS draindown line is 20.5 inches in length, and the 6-inch portion of the draindown line is 4 inches in length.

E1-1, subpart (2):

Discuss whether there are pipe whip restraints installed on the 4-inch diameter portion of the safety injection piping and on the 2-inch portion of the RCS draindown line.

NSPM Response:
There are no pipe whip restraints installed on the 4-inch diameter portion of the safety injection line or on the 3-inch diameter portion of the RCS draindown line.

E1-1, subpart (3)

If no pipe whip restraints are installed on the 2-inch diameter portion of the draindown line and 4-inch diameter portion of the safety injection line, and if pipe whip restraints on the 6-inch diameter portion of these two lines are removed as a result of the LBB approval, justify how the 6-inch diameter portion of these two lines is protected, should the 2-inch portion of the draindown line or the 4-inch diameter portion of the safety injection line fail in a double-end guillotine break.

NSPM Response:
The 6-inch diameter portion of these lines is protected by existing pipe whip restraints. Approval of LBB on the 6-inch portions of these lines allows for the elimination from consideration of the dynamic effects of pipe rupture only for the 6-inch breaks. The dynamic effects of pipe ruptures occurring on the 4-inch portions of these lines, for which LBB technology has not been applied, must still be considered. The restraint system must maintain its ability to protect safety-related systems, structures, and components (SSCs) from the effects of pipe whip and jet impingement due to those smaller ruptures, which will remain within the design basis.

NSPM has no current plans to remove the whip restraints from the 6-inch SI lines. Any future plans to remove the existing pipe whip restraints would need to demonstrate analytically that

ruptures occurring on the smaller bore portions of the line would not result in a plastic hinge and pipe whip that could damage safety-related SSCs.

E1-2. Page 7: *The licensee stated that when LBB was applied to the RCS loop piping in an LBB evaluation in 1986, a criterion of 1 gallon per minute (gpm) in one hour for RCS leakage was used for the leak detection system capability. However, for the current submittal, the licensee used a leakage detection limit of 0.2 gpm. The use of 0.2 gpm in the proposed LBB evaluation is an improvement in the leakage detection capability from the original licensing basis of 1 gpm. However, discuss whether the design basis for the RCS leak detection system needs to be changed in the Updated Final Safety Analysis Report and plant technical specifications via a license amendment process. If not, provide justification.*

NSPM Response:
NSPM response to this question regarding RCS leak detection will be provided separately.

Enclosure 2 to the December 22, 2009 Submittal (SIA 0900634.401 – LBB for RCS Piping)

E2-1. Page 1-1:

E2-1, Subpart (1):

Identify the material specification of the subject pipes and welds for LBB (e.g., SA designation).

NSPM Response:
The piping materials are A-376, Type 316 stainless steel, and the welds are stainless steel welds that were completed using the shielded metal arc welding (SMAW) process.

E2-1, Subpart (2):

Provide material properties of the pipes and welds because Table 4-1a provides only materials properties for the lower-bound shield metal arc welding process.

NSPM Response:

The material properties for the base metal/piping and the welds are shown in the following table:

TABLE : Material Properties for Piping and SMAW

Parameter	Piping A-376, Type 316*	SMAW
Temp (°F)	550	550
E (ksi)	25,500	25,000
Sy = σ_O (ksi)	29.6	49.4
Su (ksi)	58.1	61.4
Sf = 0.5 (Sy + Su) (ksi)	43.85	55.4
Ramberg-Osgood Parameter α	12	9.0
Ramberg-Osgood Parameter n	4.80	9.8
JIC (in-k/in2)	10.7	0.288
J-R Curve Parameter C1 (in-k/in2)	36.3	3.816
J-R Curve Parameter N	0.594	0.643
Jmax (in-k/in2)	12	2.345

* Material properties of Gas Tungsten Arc Weld (GTAW) material used for the root pass are assumed to be similar to the base material A-376, Type 316. For LBB purposes, the fracture toughness properties of the material have the most influence on the results of the critical flaw size analyses and leakage rate calculation, as mentioned in Section 4.2 of Enclosure 2 to the Reference 1 LAR. In that sense, GTAW metal has been shown to exhibit net section plastic collapse behavior similar to the stainless steel (SS) base metal. Based on the screening criteria of Section XI, Appendix C of the ASME Code, GTAW and SS base metal are grouped in the same category and can be analyzed with limit load methodology while SMAW metals which have a lower toughness need to be evaluated using elastic-plastic fracture mechanics methodology. The material property information listed above was previously provided to the NRC for a Leak-Before-Break license amendment request for the R.E. Ginna Nuclear Power Plant and was approved in Reference 2.

E2-1, Subpart (3):

Identify any piping analyzed for LBB in Enclosure 2 that contains Alloy 82/182 dissimilar metal welds.

NSPM Response:
There are no Alloy 82/182 dissimilar welds in the piping analyzed in Enclosure 2 to Reference 1.

E2-2. Page 1-5: *Table 1-1 presents 12 leak detection systems at Prairie Island with detectable leakage and response time. The licensee stated that Prairie Island has a very redundant leak detection system capable of detecting leakage as low as 0.1 gpm, but it is being conservative by using a leak detection capability of 0.2 gpm in the LBB analysis. The NRC staff questions the capability of the 12 detection systems and methods having the necessary redundancy and sensitivity to meet the specifications in Regulatory Guide (RG) 1.45, Revision 1. First, of the 12 detection systems and methods listed in Table 1-1, only five monitoring methods can detect a minimum leakage of 0.2 gpm or lower. Of the five monitoring methods, the operator inspection method, the daily coolant inventory method, and the sump pump operating time method would not satisfy the RG 1.45 requirement of a response time of 1 gpm within 1 hour. The remaining two monitoring methods may be acceptable. The containment radioactive particulate monitor R-11 has an estimated response time of 1 hour for a leakage rate of 0.5 gpm and it can detect a minimum of 0.1 gpm. The licensee may also take credit for the containment relative humidity monitoring which can detect a minimum leakage of 0.2 gpm with an estimated response time of 2 hours for a 0.5 gpm leakage.*

E2-2, Subpart (1):

Of the 12 leak detection systems in Table 1, confirm which leak detection systems satisfy RG 1.45.

NSPM Response:
NSPM response to this question regarding RCS leak detection will be provided separately.

E2-2, Subpart (2):

On page 1-4, the licensee stated that Table 1-1 was taken from Reference 5, which is related to the PINGP coolant leakage detection system performance and was submitted to the NRC on March 31, 1976. The information in Table 1-1 is more than 30 years old. Identify the leakage detection systems and methods at Units 1 and 2 that satisfy RG 1.45, Revision 1, in terms of redundancy, reliability, and sensitivity per Standard Review Plan (SRP) Section 3.6.3.III.4.

NSPM Response:
NSPM response to this question regarding RCS leak detection will be provided separately.

E2-2, Subpart (3):

Provide the response time for the detectable leakage of 0.2 gpm because Table 1-1 presents response time based on the leakage of 0.5 gpm, 1.0 gpm and 5.0 gpm, and not 0.2 gpm.

NSPM Response:
NSPM response to this question regarding RCS leak detection will be provided separately.

E2-3. Page 4-5. Item 3: *Explain why normal operating pressure is multiplied by 1.01 for the critical flaw size calculation.*

NSPM Response:
The nominal Reactor Coolant System (RCS) operating pressure is 2235 psig. In actual practice, operational fluctuations sometimes result in sustained RCS pressures as high as 2253 psig. In order to bound the anticipated range of pressures in service, a 1.01 multiplier has been applied to the nominal pressure to account for these fluctuations. Note that the higher pressure is used for critical flaw size calculations since it results in smaller, conservative flaw sizes, while the nominal pressure is used in leakage calculation to yield lower, thus more conservative leakage results.

E2-4. Page 4-6, Item 8:

E2-4, Subpart (1):

Explain why not all the nodes reported in the subject LBB evaluation have updated loading data due to the uprate conditions and why there is no stress analysis performed on the subject piping considering uprate conditions.

NSPM Response:

The Measurement Uncertainty Recapture (MUR) Power Uprate itself had very little effect on the normal and upset portions of the pipe stress analysis for the RCS branch lines because it resulted in only a 0.5 degree Fahrenheit increase in the RCS hot leg temperature, and a 0.5 degree Fahrenheit decrease in the cold leg temperature, which would have resulted in insignificant changes to the thermal stresses in the branch piping. However, in conjunction with the MUR Uprate project, several additional design discrepancies were reconciled, including the fact that the original pipe and component stress analyses used temperatures different than actual plant operating T-hot and T-cold values. In addition, the branch piping analyses often had not considered anchor displacements at the RCS nozzles due to Loss of Coolant Accident (LOCA) loads.

The RCS branch line piping and nozzles were re-qualified under the MUR power uprate project to consider thermal stresses representing actual temperatures under MUR conditions and to include in the anchor movements faulted case the Safe Shutdown Earthquake (SSE) plus LOCA combination. However, the branch lines themselves were not subject to complete dynamic reanalysis. Rather, for the highest stressed location for each branch line, the thermal stresses were extracted and then scaled to adjust for the uprate temperature conditions compared to the as-analyzed conditions.

Likewise, the anchor movement stresses were extracted from the analysis of record and scaled to adjust for the revised total SSE plus LOCA anchor movements. The revised thermal and anchor movement stresses were then combined with the other stresses in the original stress analysis and compared to the allowable stress in order to check the qualification of each line. Because this method was used, and only the bounding highest stress location in a given pipe run was checked for qualification, the uprate work did not develop new stress results for every node on a given RCS branch line. New stresses were, however, calculated for each RCS branch nozzle.

E2-4, Subpart (2):

Explain why node 1045 in the 6-inch diameter safety injection line in Table 4-10 was selected as the limiting node even though its leakage was not limiting as shown in Table 5-9.

NSPM Response:
The designation of the limiting node is complicated by the fact that Table 5-9 of Reference 1 includes two nodes with a '1045' designation. The distinction is clarified in the accompanying notes for Table 5-9 which explain that "Node 1045" is attached to the cold leg, and "Node 1045*" is attached to the reactor pressure vessel.

Table 5-9 identifies the following leak rates:

Node 1045	4.600 gpm
Node 1045*	4.902 gpm

Based on the above, the leak rate for Node 1045 is smaller and therefore limiting, which is the basis for its inclusion in Table 4-10.

E2-5: *Not used.*

E2-6. Page 4-19: *Clarify why the "normal operation and [safe shutdown earthquake] SSE" moment and leakage flaw size for node 1045 of the 6-inch diameter safety injection line in Unit 1 in Table 4-10 are not the same as the moment and leakage flaw size for node 1045 in Table 5-9.*

NSPM Response:
The moment and leakage flaw size for Node 1045 in Table 4-10 (Reference 1) are the same as the moment and leakage flaw size for Node 1045 in Table 5-9 (5th row from the bottom). Note that this Node 1045 in Table 5-9, which is attached to the cold leg, is different from Node 1045*, which is attached to the reactor pressure vessel. In addition, Table 5-9 identifies the 'leakage flaw size (a)' which is one half the 'total flaw length (2a)' provided in Table 4-10, as clarified in the Notes for each table.

E2-7. Page 5-3, second paragraph, and Figure 5-1: *For the J-R power-law representation, discuss the crack extension that was used to calculate the toughness slope dJ/da.*

NSPM Response:
Figure 5-1 in Reference 1 is for illustration purposes only. Definition of J-R curve used for the LBB evaluation and the associated crack extension is consistent with NUREG/CR-6428 (Reference 3, page 24, Figure 18), as also stated in Enclosure 2, Page 4-2, 10th row from the top of the section. A detailed discussion of the crack extension is provided in NUREG/CR-6428.

E2-8. Pages 5-7 to 5-12: *Explain why the stress corrosion cracking morphology in leak rate calculations is discussed in this report even though it does not appear that the subject pipes contain Alloy 82/182 weld material or Alloy 600 material.*

NSPM Response:
There is no Alloy 82/192 weld material or Alloy 600 material in the subject pipes. A sensitivity study was performed to compare leakage calculated using fatigue morphology parameters and leakage calculated using PWSCC morphology (Tables 5-24 and 5-25 of Reference 1, Enclosure 2). Section 5.4.2 of Reference 1, Enclosure 2 describes the results, and notes that PWSCC is not considered to be credible. Therefore fatigue crack morphology is used.

E2-9: *Page 6-1, second paragraph, states that "...Although there was a safety injection transient in Unit 1 due to [steam generator] tube rupture in 1979, there have been no inadvertent safety injections since. This transient is therefore also considered unlikely and was not evaluated..." The fact that a safety injection did occur in 1979 shows that the safety injection transient is a likely event and should be considered in the fatigue crack growth calculation. Justify why the inadvertent safety injection should not be considered in the evaluation, and discuss the actions/measures that preclude the potential for having an inadvertent safety injection*

NSPM Response:
The stress intensity factor range (ΔK) associated with the inadvertent safety injection due to the tube rupture is estimated to be 0.428 ksi·in$^{1/2}$. Since plant startup, only one such event has taken place. If it is conservatively estimated that 10 cycles of this event will occur for the balance of plant life, then the calculated crack growth for these 10 cycles is 2.46×10^{-8} inches, which is small compared to the final crack size of 0.0839 inches in Table 6-13 of Reference 1. Therefore, not including this transient in the fatigue crack growth evaluation does not change the conclusions of the analysis.

Many of the potential causes of inadvertent safety injection events are related to breaks in steam lines or a steam generator tube rupture, which was the cause of the inadvertent safety injection event at PINGP in 1979. Periodic inspections of steam generator tubes and plugging of tubes when necessary are performed to minimize the likelihood of such events. These actions also minimize inadvertent safety injections and there have been no such events in over 30 years of operation at PINGP.

E2-10: *Page 6-1, second paragraph, states that "...There are no local piping system transients for the 6-inch draindown line and the 6-inch hot leg nozzles..."*

E2-10, Subpart (1):

Explain why there are no local piping system transients for the 6 inch draindown line and the 6-inch hot leg nozzles. Discuss the transients that were used for these two lines in the analysis.

NSPM Response:
All local piping system transients are described in Table 6-2 of Reference 1. These transients do not affect the draindown line or the hot leg nozzles. These two lines experience only the transients described in Table 6-1, and no additional local transients are considered for these two lines. Only hot leg transients described in Table 6-3 are applied to these two lines because they are attached to the hot leg.

E2-10, Subpart (2):

Discuss whether there are local piping system transients or design transients applied to other pipes in the LBB evaluation.

NSPM Response:
There are local piping system transients applied to other pipes. For example, as shown in Table 6-2 of Reference 1, the "High Head Safety Injection" transient is applied to 6-inch cold leg Safety Injection lines, the "Residual Heat Removal (RHR) operation at Cooldown" transient is applied to 12-inch SI accumulator lines, the "Refueling Floodup" transient is applied to 12-inch SI accumulator lines, and the "RHR initiation" transient is applied to 8-inch RHR suction lines.

E2-10, Subpart (3):

Explain the "local" piping system transients as opposed to the design basis transients or non-local transients.

NSPM Response:
"Local" piping system transients affect only certain piping lines. As an example, transients in Table 6-2 of Reference 1 affect only certain piping lines. However, design basis transients /non-local transients (such as the transients shown in Table 6-1) affect the entire piping system.

E2-10, Subpart (4):

Discuss the thermal transients of the reactor coolant system draindown line and whether the thermal transients were included in the analysis.

NSPM Response:
The thermal transients for the hot leg (Table 6-3, Reference 1) are used as the thermal transients for the draindown lines because the draindown lines are attached to the hot leg.

E2-11. Pages 6-2 and 6-3: *Section 6-2 discusses various stresses for crack growth evaluation. Explain why stresses due to seismic event were not discussed.*

NSPM Response:
Operating Basis Earthquake (OBE) stresses should have been mentioned explicitly in Section 6-2 of Reference 1. They are only implicitly mentioned in Section 6-1 which refers to the tables (Tables 6-1, 6-2, etc...) for a list of plant transients used. Nonetheless, OBE stress was included in the fatigue crack growth calculation. The stress due to OBE is included in the stress range calculation in combination with other plant conditions as shown in Tables 6-3 and 6-4.

Enclosure 3 to the December 22, 2009 Submittal (SIA 0900634.402, LBB for Pressurizer Surge Line)

E3-1. Page 1-1: *The licensee stated that it has installed the weld overlay on the Alloy 82/182 dissimilar metal weld on the pressurizer surge line at PINGP Unit 2.*

E3-1, Subpart (1):
Discuss whether the weld overlay is installed on the pressurizer surge line at Unit 1.

NSPM Response:
No weld overlay has been applied to the Unit 1 Pressurizer Surge Line as there are no 82/182 dissimilar metal welds in this line.

E3-1, Subpart (2):
Discuss inspection results of the overlaid Alloy 82/182 dissimilar metal weld(s) at Unit 2 pressurizer surge line.

NSPM Response:
The weld was subjected to Ultrasonic Testing (UT) prior to the application of the weld overlay using a full Performance Demonstration Initiative (PDI) qualified technique. There were no relevant indications. Following the overlay, the weld was subjected to pre-service ultrasonic examination in accordance with ASME Section XI, Appendix VIII, Supplement 11, as modified in Relief Request 2-RR-4-8 Rev.1. No relevant indications were identified.

The surge line nozzle was also examined during the recent refueling outage of Unit 2 that was completed in May 2010, and no flaws were identified.

E3-1, Subpart (3):

Provide the weld identification number for the Alloy 82/182 welds that have been weld overlaid.

NSPM Response:
The Alloy 82/182 weld is the surge-nozzle-to-safe-end weld, identified as W-17. The overlay itself is identified as W-18.

E3-2. Page 4-2, Section 4.2:

E3-2, Subpart (1) :

Discuss whether the weight of the weld overlay is included in the applied loads in the LBB evaluation. If not, provide justification.

NSPM Response:
The Pressurizer Surge Line and Surge Nozzle were evaluated for the effect of the increased weight and stiffness due to the overlay, as part of the overlay design process. These effects were determined to be negligible on the piping and component loadings. The LBB evaluation subsequently used the design loads for the surge nozzle overlay for the dead weight and seismic inputs, which bound the actual loads from the pipe stress analysis by a large margin. If the loads computed from the pipe stress analysis were used instead, the LBB margins would be increased from what has been calculated.

E3-2, Subpart (2):

Clarify whether the loadings used in the LBB analysis are applicable for 60 years for the period of license renewal.

NSPM Response:
Yes. The loads used in the LBB analysis are applicable for 60 years.

E3-3. Page 4-4, second paragraph: *The licensee stated that the thermal stratification loads are lower than safe shutdown earthquake (SSE) load as shown in Table 4-2 of Enclosure 3; thus, thermal stratification during heatup/cooldown is ignored. Justify why the thermal stratification loads in Table 4-2 are ignored because the moment in the y direction for the thermal stratification is not insignificant compared to the SSE load. If the moments for the thermal stratification in the y direction (My) are included with the SSE load in the analysis, the critical crack size and leakage crack size may be changed from the reported value in the submittal.*

NSPM Response:
For LBB evaluation, loads are used as total moments, i.e. square root of the sum of squares (SRSS) of moments from the three directions (x, y, z). The SRSS moments due to thermal stratification are approximately 19% of the SSE moments. As stated on Page 4-4 of Reference 1, the durations of the transients (e.g., heatup) which cause the large stratification loads are relatively short, and the likelihood of an SSE occurring during those events is extremely low. Therefore, it is reasonable to use the larger of the loads from SSE or stratification in the LBB evaluation

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E3-4. Page 7-1, first paragraph: *The licensee stated that "...Crack growth evaluations were performed in Reference 6 to indicate that combined PWSCC and fatigue crack growth for axial and circumferential postulated flaws is within acceptable limits for [time period - proprietary information] operating interval..."*

E3-4, Subpart (1):
Provide the acceptable limits and the starting point of the stated time period.

NSPM Response:
The acceptable limits for postulated axial and circumferential flaws for the full structural weld overlay design are 75% of the total thickness based on ASME Code Section XI acceptance criteria. The starting point is the time of installation of the weld overlay (2008).

E3-4, Subpart (2):

Based on the results, the postulated flaw(s) will exceed the acceptable limits before the end of the plant license and license renewal period. Discuss how the subject pipe will be monitored to prevent flaws from exceeding the acceptable limits.

NSPM Response:

The evaluation period identified in Enclosure 3 of Reference 1 was chosen to bound the remaining service life of Prairie Island Unit 2. The weld overlay was installed in 2008, and the License Renewal Period of Extended Operation for Unit 2 expires in 2034. The evaluation determined that an initial assumed 360 degree circumferential 75% through-wall flaw in the original weld will not exceed ASME Section XI acceptance criteria for the overlayed configuration within the remaining service life.

As additional assurance, the weld overlay on the Unit 2 Pressurizer Surge Line is required to be re-inspected ultrasonically every ten years by MRP-139 and ASME Code Case N-770, so the weld is established as having no cracking every ten years, thus resetting the clock on crack growth to zero and renewing the qualified life of the weld. This re-inspection will occur through the remainder of current license period and through the license renewal period of extended operations.

Enclosure 4 to the December 22, 2009 Submittal (Westinghouse WCAP-15379)

E4-1. Page 2-1: *Section 2.1 implies that stress corrosion cracking in the RCS primary loop and connecting Class 1 lines is a low probability event. The pressurizer surge line at Unit 2 contains Alloy 82/182 dissimilar metal welds, which are susceptible to primary water stress corrosion cracking (PWSCC) based on pressurized-water reactor (PWR) operating experience.*

E4-1, Subpart (1):

In light of Alloy 82/182 welds in the surge line, explain why Section 2.1 stated that stress corrosion cracking is a low probability event and did not discuss the PWSCC issue in the pressurizer surge line. The NRC staff understands that Enclosure 3 of the submittal covers the Alloy 82/182 and PWSCC issue for the Unit 2 surge line. However, Enclosure 4 should also address the issue.

NSPM Response:

The LBB analysis for the Unit 2 pressurizer surge line is a two-part analysis, as described in Enclosure 1 to Reference 1 (pages 6 and 7). This analysis includes both the Westinghouse analysis performed in 2000 (Enclosure 4 to Reference 1), and the Structural Integrity analysis (Enclosure 3 to Reference 1). The Structural Integrity analysis addresses a subsequent configuration change to the Unit 2 pressurizer surge line involving the addition of a weld overlay to provide a PWSCC resistant barrier to the 82/182 nozzle-to-safe-end weld.

Enclosure 4 was prepared in the early part of 2000 before the industry concern related to PWSCC cracking in the primary loop piping nozzle at Alloy 82/182 locations started (e.g., V.C. Summer cracks in the hot leg piping in late-2000, as discussed in NRC Information Notice 2000-17). Therefore, PWSCC was not specifically addressed in the analysis in Enclosure 4.

The Structural Integrity analysis in Enclosure 3 to Reference 1 is considered a supplement to the Westinghouse analysis in Enclosure 4 to Reference 1, and provides a thorough evaluation of PWSCC issues at the 82/182 dissimilar metal weld in the pressurizer surge line. The combined analyses in Enclosures 3 and 4 adequately address PWSCC issues and no change to Enclosure 4 is necessary.

E4-1, Subpart (2):

Provide any prior occurrences of fatigue cracking or PWSCC in the Unit 2 pressurizer surge line.

NSPM Response:

There have been no instances of fatigue cracking or PWSCC in the Prairie Island Unit 2 pressurizer surge line.

E4-2. Page 2-2, Section 2.2: *Provide quantitative information about historic frequencies on water hammers in Unit 2 pressurizer surge piping.*

NSPM Response:
The reactor coolant system is designed and operated to preclude any voiding condition in normally filled lines. There should not be any water hammer in the surge line piping system, and the Prairie Island Unit 2 pressurizer surge line has never been subject to a known water hammer event.

E4-3. Page 2-1, Section 2: *Based on PWR operating experience, the pressurizer surge line is susceptible to thermal stratification, which is a form of thermal-induced fatigue. SRP Section 3.6.3.III.10 does not permit LBB to be applied to piping with a history of fatigue cracking or failure. The licensee did not discuss thermal stratification in Section 2.0. Discuss whether thermal stratification is a concern in the pressurizer surge line at PINGP Unit 2. If not, provide technical basis.*

NSPM Response:
Based on known data there has been no cracking in Westinghouse designed surge lines. There was one case in 1989 where the Trojan plant replaced a surge line nozzle for what was believed to have been a flaw. Subsequent examination of the nozzle did not identify any flaws. Therefore, there is no known history of surge line cracking.

A surge line thermal stratification analysis was performed for Prairie Island Unit 2 to address Generic Letter 88-11, which required licensees to evaluate pressurizer surge lines for fatigue due to the effects of thermal stratification. This analysis was based on WCAP-12639 (Reference 4) and WCAP-12639 Supplement 1 (Reference 5) reports and was approved by the NRC (Reference 6). The License Renewal Application for PINGP Units 1 and 2 also described the stratification analysis and usage factor information in Sections 4.3.1.3 and 4.3.1.6 (Reference 7).

Thermal stratification is not a concern in the pressurizer surge line at Prairie Island Unit 2. Loads from thermal stratification were used in the LBB analysis.

E4-4. Pages 4-1 to 4-5: *Section 4.4 states that load cases A, B, and C are normal operation conditions and D, E, F, and G are faulted conditions. There should be 12 loading combinations of normal operation conditions and faulted conditions: A/D, A/E, A/F, A/G, B/D, B/E, B/F, B/G, C/D. C/E C/F, and C/G.*

Explain why load combinations A/E, A/G, B/D, C/D, C/E, and C/F were not shown in Table 4-3.

NSPM Response:
For the Prairie Island pressurizer surge line LBB application with stratification loadings, Westinghouse established the various loading cases and combinations which have been accepted by the NRC in previous LBB applications including the Prairie Island Unit 1 surge line. Section 4.4 and Tables 4-2 and 4-3 of Enclosure 4 to Reference 1 provide the loading scenario and possible combination cases. Loading Case E (faulted) has the normal operating steady state stratification loads that should be combined with loading Case B which has normal operating steady state stratification loads. Similarly, Loading Case D (faulted) has the normal operating thermal loads that should be combined with the normal operating loading Case A which has normal operating thermal loads. Therefore, the logical combinations for the LBB analyses are Case A/D and Case B/E and these combinations and are considered acceptable. Cases A/F and B/F depict postulated forced cooldown at normal operating temperatures with stratification to determine the pipe stability during a cool-down to repair a leak. Combination of B/G and C/G are other low probability cases; however, they are conservatively included.

Load combinations A/E, A/G, B/D, C/D, C/E, and C/F are not included in the LBB evaluations for the following reasons:

- Loading Case E (faulted) has the normal operating steady state stratification loads that should not be combined with loading Case A which has normal operating thermal loads.
- Loading Case G (faulted) has the maximum stratification loads during heat-up and cool-down that should not be combined with loading Case A which has normal operating thermal loads.
- Loading Case D (faulted) has the normal operating thermal loads that should not be combined with loading Case B which has normal operating steady state stratification loads.
- Loading Case D (faulted) has the normal operating thermal loads that should not be combined with loading Case C which has the maximum stratification loads during heat-up and cool-down.
- Loading Case E (faulted) has the normal operating steady state stratification loads that should not be combined with loading Case C which has the maximum stratification loads during heat-up and cool-down.
- Loading Case F (faulted) has the forced cool-down stratification loads that should not be combined with loading Case C which has the maximum stratification loads during heat-up and cool-down.

Based on the above, it is concluded that A/E, A/G, B/D, C/D, C/E, and C/F are not logical loading combinations and should not be included in the LBB evaluations.

E4-5. Page 4-5, Table 4-2:

E4-5, Subpart (1):
Explain how the temperatures are derived in each of the load cases in Table 4-2.

NSPM Response:
Normal operating temperatures, normal operating stratification temperatures, and maximum stratification temperatures were derived from the observed data provided in WCAP-12639 (Reference 4) and shown in Tables 4-1 and 4-2 of the Unit 2 LBB WCAP report. Table 4-1 shows the pressurizer and hot leg temperatures for the various stratification cases. Similar temperatures and stratification cases were used in Prairie Island Unit 1 surge line LBB analysis (Reference 8) which was accepted by the NRC.

E4-5, Subpart (2):
Discuss whether loads caused by insurge and outsurge have been considered in the LBB evaluation. If not, provide justification.

NSPM Response:
The stratification stages represent initial/final conditions bounding insurge and outsurge transients and therefore, loads from insurge and outsurge were considered in the LBB evaluation

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E4-6. Page 4-7: *Table 4-4 provides loading for critical location, Node 1320.*

E4-6, Subpart (1):
Discuss how the critical location, Node 1320, was selected.

NSPM Response:
Node 1320 was selected as the critical location because it has the maximum faulted stress.

E4-6, Subpart (2):

To aid in necessary confirmatory calculations, provide all load components (i.e., moments in the x, y, and z directions and Fx) for each ASME loading category case (A, B, C and D) for Node 1320.

NSPM Response:

Individual (x, y, and z) loading components for some loading cases are not available. To support confirmatory calculations for leak rate and critical flaw size calculations, the following values of Fx and the resultant moments for Node 1320 are provided:

Node	Case	Fx (lbs)	M_B (in-lb)
1320	A	132,521	298,625
1320	B	132,383	228,098
1320	C	21,470	1,199,059
1320	D	137,572	414,954

E4-6, Subpart (3):

Discuss whether the pipe loadings for the LBB evaluation include the effect of the power uprate conditions. If not, provide justification.

NSPM Response:

LBB evaluation for the MUR uprate was not performed specifically for the Unit 2 surge line because LBB was not approved for Unit 2 at the time the analysis was performed in 2000. The PINGP MUR uprate program was reviewed and has been determined to have an insignificant impact on the surge line, as discussed previously in the reply to RAI E2-4, Subpart (1).

E4-7. Page 5-3: *first paragraph, states that the crack relative roughness was obtained from fatigue crack data of stainless steel samples. Discuss the source of the stainless steel samples. Discuss how the roughness value was obtained.*

NSPM Response:

Westinghouse previously developed crack relative roughness values which have been submitted to and accepted by the NRC. WCAP-9558 (Proprietary), Revision 2, "Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Through-wall Crack" dated May 1981 documented the crack relative roughness that was used for the fracture mechanics LBB leak rate calculations. WCAP-9558 (Proprietary), Revision 2 was approved by the NRC in Reference 9. Since 1981, Westinghouse has applied this crack relative roughness value for similar LBB applications including Prairie Island Unit 1 surge line (WCAP-12877, Reference 8).

E4-8. Page 5-3: *Section 5.2.3 states that the crack opening area was estimated using the method of Reference 5-3. Discuss in detail exactly how the crack opening area was estimated and provide page numbers in Reference 5-3 which show the crack opening area calculation.*

NSPM Response:
The crack opening areas were calculated based on NUREG/CR-3464, pages 71 through 81. The crack opening area estimation is based on linear elastic fracture mechanics (LEFM), including effects of shell corrections. The imposed loads on the circumferential flaw are the axial tensile force and bending moment due to normal operating conditions (e.g. deadweight, pressure, thermal expansion). The crack opening area for the tensile loading is obtained by the energy method (Castigliano's theorem). The crack opening area for the bending load is obtained by further derivation as shown on pages 76 through 80 of NUREG/CR-3464. The two crack opening area components (tension and bending) are combined to determine the total crack opening area. Similarly, since 1981, Westinghouse has used this crack area calculation method for other LBB applications that have been reviewed by the NRC including the Prairie Island Unit 1 surge line (WCAP-12877, Reference 8).

E4-9. Pages 5-11 to 5-14: *Discuss how the curves on these pages were constructed.*

NSPM Response:
Figures 5-6 through 5-9 of Reference 1, on pages 5-11 through 5-14 graphically represent the various limit moments versus the critical flaw sizes, and were developed using the equations shown in Appendix A and in Section 5.1 of Reference 1, Enclosure 4. They also illustrate the circumferential critical flaw size using the governing faulted loads.

E4-10. Page 6-1: *The licensee did not perform a fatigue crack growth calculation for Unit 2 pressurizer surge line. Instead, it used the results of the Unit 1 fatigue crack growth calculation to apply to the Unit 2 fatigue growth calculation. Unit 1 selected location 1 is near the reactor coolant loop nozzle and location 2 is located near the pressurizer nozzle.*

E4-10, Subpart (1):

Discuss whether the same locations in the Unit 2 surge line have the same loading as the two locations in the Unit 1 surge line.

NSPM Response:
In WCAP-15379 (Unit 2), the critical location was Node 1320 based on the highest faulted stress along the entire surge line. A comparison of the loading cases at this location (Table 4-4 of WCAP-15379) for Unit 2 shows that the stresses are bounded by the pressurizer nozzle location at Unit 1 (Node 1240 of Unit 1 in WCAP-12877, Reference 8, Table 4-4). Node 1240 of Unit 1 in WCAP-12877 has the higher faulted stress than Node 1020 for Unit 1 and therefore Node 1240 governs. As a result, the limiting fatigue crack growth results of Unit 1 at Node 1240 will be applicable for the Unit 2 fatigue crack growth.

E4-10, Subpart (2):

Discuss how it was determined that the two pipe locations in the Unit 1 pressurizer surge line will be the same limiting locations in the Unit 2 pressurizer surge line.

NSPM Response:

The piping stresses at Node 1240 (Unit 1 in WCAP-12877, Reference 8, Table 4-4) are higher than those of Node 1320 (Unit 2 in WCAP-15379). Because Node 1320 of Unit 2 is the governing LBB location for the entire surge line and also Node 1240 envelops Node 1320, the fatigue crack growth results from Unit 1 for Node 1240 will bound any fatigue crack growth results on Unit 2 Node 1320. It should be noted that the limiting fatigue crack growth results are at Node 1240 of Unit 1. Also the surge line transients and geometry are comparable between the two units. Additionally the results show that the fatigue crack growth is insignificant.

E4-10, Subpart (3):

Discuss whether the applied loads and stresses at the Unit 1 surge line bound the applied loads at the Unit 2 surge line.

NSPM Response:

Based on Tables 4-4 in WCAP-12877 (Reference 8) for Unit 1 and WCAP-15379 in Unit 2, the surge line loads at the highest stressed location in Unit 1 (Node 1240) bound the applied loads at the highest stressed location in Unit 2 (Node 1320).

E4-11. Page A-1: *Cite reference(s) for the equations presented in Appendix A.*

NSPM Response:

Appendix A provides the limit moment equations which are also provided in Section 5.1 of Enclosure 4 to Reference 1. These are Westinghouse derived equations similar to methodology and the equations provided in EPRI NP-192 (Reference 10 below, also identified as Reference 5-1 in WCAP-15379, Enclosure 4 to Reference 1), and Section XI, Appendix C of the ASME Code

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References for Enclosure 1

1. Letter from Northern States Power Company, a Minnesota corporation, to the Nuclear Regulatory Commission, "License Amendment Request to Exclude the Dynamic Effects Associated with Certain Postulated Pipe Ruptures From the Licensing Basis Based Upon Application of Leak-Before-Break Methodology," L-PI-09-134, dated December 22, 2009, ADAMS Accession Number ML100200129.

2. Letter from G. S. Vissing (USNRC) to R. C. Mecredy (Rochester Gas and Electric Corporation), "Staff Review of the Submittal by Rochester Gas and Electric Company to Apply Leak-before-Break Status to Portions of the R. E. Ginna Nuclear Power Plant Residual Heat Removal System Piping (TAC No. MA0389)," dated February 25, 1999.

3. NUREG/CR-6428, Effects of Thermal Aging on Fracture Toughness and Charpy–Impact Strength of Stainless Steel Pipe Welds, US NRC, May 1996.

4. WCAP-12639, "Westinghouse Owners Group Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis Program MUHP-1091 Summary Report," June 1990.

5. WCAP-12639 Supplement 1, "Westinghouse Owner's Group Additional Information on Pressurizer Surge Line Stratification Detailed Analysis," November 1990.

6. NRC letter to NSP dated December 20, 1991, "Prairie Island Nuclear Generating Plant Unit No 2- Pressurizer Surge Line Thermal Stratification- Bulletin 88-11."

7. Xcel letter to US NRC Document Control Desk, "Application for Renewed Operating Licenses Prairie Island Nuclear Generating Plant Units 1 and 2," April 11, 2008.

8. WCAP-12877, "Technical Justification for Eliminating Pressurizer Surge Line Rupture as the Structural Design Basis for Prairie Island Unit 1," March 1991.

9. NRC "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops (Generic Letter 84-04)," February 1, 1984.

10. EPRI NP-192, "Mechanical Fracture Predictions for Sensitized Stainless Steel Piping with Circumferential Cracks," Kanninen, M. F. et al., September 1976.